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Investment in wind power and pumped storage in a real options model

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ABSTRACT

Promoting renewable energy has been a key ingredient in energy policy seeking to de-carbonize the energy mix and will continue to do so in the future given the European Union's high ambitions to further curb carbon emissions. A wide range of instruments has been suggested and implemented in various countries of the EU. A prominent policy promoting investment in renewable technologies is the use of feed-in tariffs, which has worked well at large scale in, e.g. Germany, but which has only been implemented in a very limited way in countries such as the UK.

Being subject to environmental uncertainties, however, renewables cannot be seen in isolation: while renewables-based technologies such as wind and solar energy, for example, suffer from uncertain loads depending on environmental conditions, hydropower allows for the storage of water for release at peak prices, which can be treated as a premium (partially) offsetting higher upfront investment costs. In addition, electricity prices will respond to changes in electric capacity in the market, which is often neglected in standard investment models of the electricity sector.

This paper contributes to the existing literature in two ways: it provides a review of a renewables-based technology in a specific policy context and provides additional insight by employing a real options approach to investigate the specific characteristics of renewables and their associated uncertainties in a stylized setting taking explicitly into account market effects of investment decisions. The prices of the model are determined endogenously by the supply of electricity in the market and by exogenous electricity price uncertainty. The inclusion of market effects allows us to capture the full impact of public incentives for companies to invest into wind power and hydro pumped storage installations.

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1. Introduction

According to the International Energy Agency (e.g. IEA [1]), Norway's electricity production is almost exclusively based on hydropower. However, the potentials for large-scale hydropower has been almost exhausted over the past and in the pursuit of meeting emission reduction goals without compromising the security

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of energy supply, the Norwegian government has been promoting other renewable energy sources such as small-scale hydro- and wind power. The latter is particularly attractive for Norway, as it enjoys both high wind speeds and a long coast line.

Within the European Union the most common policy to encourage the installation of renewable capacity has been feed-in tariffs to date. This works such that producers receive a fixed price for the supplied electricity, which exceeds expected market prices. Often these tariffs decrease over time. The policy for the promotion of Norwegian wind power has been an investment subsidy before the project has started. Even though it had been planned to – jointly with Sweden – introduce a market arrangement for electricity certificates to substitute for these investment subsidies from 2007 on, these plans had to be postponed until after 2010. Under this arrangement, as outlined in [2] consumers will have to buy a certain amount of certificates for their electricity bought and eligible power plants will yield certificates for the electricity producers which can be sold. Policymakers then decide upon the type of electricity production, which should be eligible, and on the respective amount of certificates. This way countries can exploit renewable resources and distribute the burden to the producers in the most efficient way. The aggregate quota will thus be attained at a lower total cost compared to feed-in tariffs or quotas.

Under this arrangement, retailers will have to buy certificates for a certain percentage of the electricity being sold and eligible producers can sell certificates, where policymakers decide upon the type of electricity production, which should be eligible as explained before, and on the height of the before-mentioned percentage.

Fleten and Ringen [2] use a real options approach taking into account the uncertainty from certificate price fluctuations to estimate the amount of new renewable capacity coming online under such a joint Swedish-Norwegian electricity certificate scheme. In this study, we want to focus on the current policy of investment subsidies.

In addition to the policy context, another factor that we want to take into account in our analysis is the intermittency of wind power, which has tended to make it an unattractive option next to fossil-fuel-fired generation options (Lund and Paatero [3]). In a related study, Paatero and Lund [4] explored how the integration of energy storage with individual wind turbines could smooth out the wind speed fluctuations. Their results for different types of wind conditions illustrated that short-term wind power fluctuations could be substantially reduced. Gowrisankaran et al. [5] model an electricity system where a system operator optimizes the amount of generation capacity, operating reserves, and demand curtailment in the presence of variable renewable production. They find that full dispatchability of solar generation would lead to cost decreases of up to $24.3 per MWh and conclude that their analysis could also be applied with similar results to wind generation with storage.

Several studies over the past few years have further looked into technologies to realize such benefits and pumped-storage wind–hydro plants, which use reservoirs to store water previously pumped up with wind power, have been found to be profitable under particular circumstances (Anagnostopoulos and Papantonis [6]). Especially on islands, where wind potentials are high, pumped-storage wind–hydro plants have been found to be a promising option, with larger islands offering potential for even more profitable investments, where wind–hydro could even serve as base-load (e.g. Bakos [7], Bueno and Carta [8]).[1] Finally, a number of ancillary benefits add to the attractiveness of the technology. These include, inter alia, that the stored water can in emergency cases be used for consumption, irrigation, and to fight fires, etc. Also, wind–hydro plants are almost carbon-free in terms of emissions. Finally, the wind–hydro plant can contribute substantially to grid stabilization by acting as a swing producer (consuming in off-peak times to pump up the water and generating during peak times).

In Germany, E.ON, which is one of the largest electricity companies of the country, has also shown interest in pumped storage technologies and has several projects in planning. As E.ON Energie CEO Dr. Ingo Luge said in December 2010: "[. . .] Pumped-storage stations are superbly suited to balancing out the intermittent output of renewables because they can store energy very efficiently and come onstream at a moment's notice to supply zero-carbon, environmentally friendly electricity." However, most of the studies reviewed above have found that pumped-storage wind–hydro plants generally only become profitable at high electricity prices or significantly improved design and efficiency combined with high wind speeds.

In this paper we want to explore the profitability of such a system both in Norway, but also in Germany considering the impact of uncertainty on investment decisions. Uncertainty emanates from two sources in our study: the development of the electricity price, which can additionally also be influenced by new capacity additions, and the intermittency of wind, which leads to a fluctuating load and thus uncertainty in profits. We therefore want to explore pumped-storage wind–hydro plants to stabilize profits from wind. While this might appear like an attractive solution for particular demonstration cases, it has to be kept in mind that such equipment is extremely costly and it is questionable whether the premium from profit stabilization would make up for this deficiency and whether therefore public funding should rather be directed at R&D targeted at cost reductions in the first place.

We adapt the real options model presented in Reuter et al. [9] in order to capture all these elements to answer the research questions outlined above and use German and Norwegian data to get a picture of the profitability of pumped-storage wind–hydro plants in the respective countries. The model focuses on the plant and its operation and abstracts from problems of integrating wind power into the grid, which is why the results have to be interpreted with caution.

In the following, we first present the pumped-storage wind–hydro plant technology in more detail; then we explain the model, give an overview of the data and finally discuss the results.

2. A real options model for wind power investment with pumped storage

This section is divided into three sections, where first the pumped-storage wind–hydro plant technology is described in more detail, then the mathematical model is presented and finally the data are described.

2.1. Technology description

The most basic pumping station as described, e.g. in Anagnostopoulos and Papantonis [6] includes several identical pumps, which work in parallel and raise water from a lower to an upper reservoir (see Fig. 1 for schematic illustration of the flows), where it can be released later to meet peak demands.[2] The combination of such a station with a wind farm is usually referred to as a "hybrid" power plant in the literature.

[1] Note that this is especially attractive for small and isolated electricity production systems, which does of course not apply to Norway.

[2] The same study also considers different pumping technologies and compares their respective efficiencies.

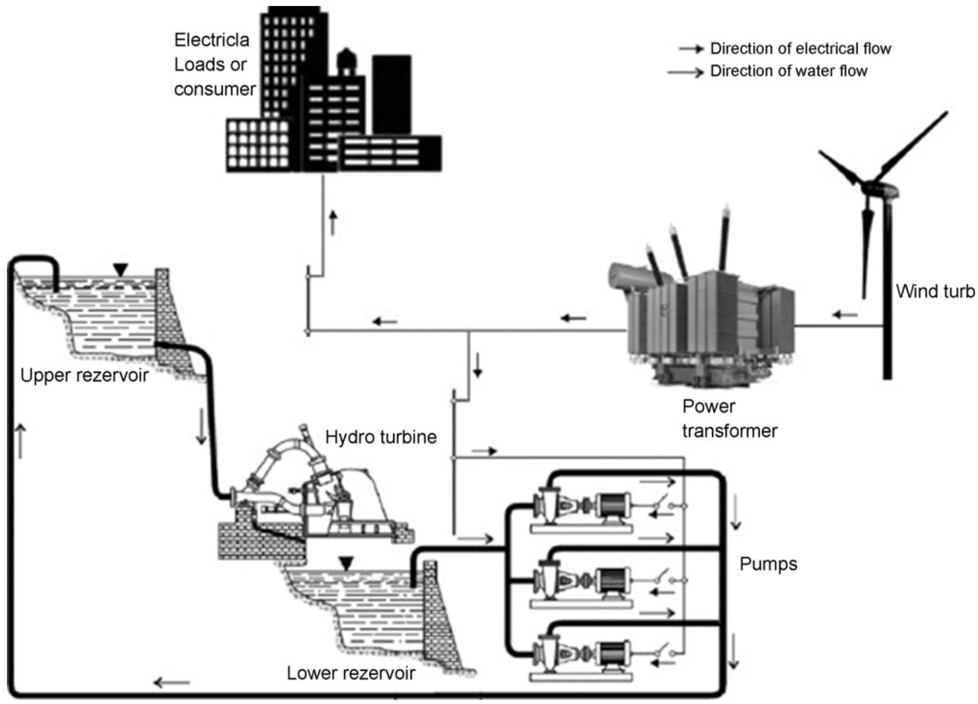

Fig. 1. Model of wind–hydro pump storage systems.

Source: Fig. 5 in Dursun and Alboyaci [10].

2.2. Model formulation

In this section we formulate the model that will be used for the analysis in Section 3. We study the profitability of the wind technology combined with pumped storage, when compared to the standard wind farms. The investor tries to find the investment strategy that maximizes expected profits during the planning period. He can decide whether and when to construct new electricity generating capacities. There are two possible technologies available: a standard wind farm (referred to as wind) and wind combined with pumped storage (referred to as wind + hydro). The assumptions underlying the model formulation can be summarized as follows:

1. The decisions can be made only once a year, the planning period is finite (T years).
2. The total number of power plants that can be built is limited to n, where only one power plant can be built during one year.
3. The load factor of both technologies is assumed to be uncertain, which leads to the annual electricity production being uncertain. Therefore, the annual electricity supply of both technologies is assumed to be equal and is denoted by q_t^w, which is modeled in each year as an independent random variable with known distribution.
4. The supply of the investor is given by the maximum quantity in that year as $q_t^w(n_t^w + n_t^h)$, where n_t^w and n_t^h denote the number of wind and wind + hydro power plants built by the investor prior to year t, respectively. The aggregate supply Q_t in year t is given by
$$Q_t = Q_0 + Nq_t^w(n_t^w + n_t^h), \tag{1}$$
where Q_0 is the quantity supplied by firms that do not invest during the planning period and the quantity produced by plants outside the planning period, i.e. which already existed in $t = 0$. N is the multiplier of the new investment. This represents the assumption that the new investment in the market is of the same structure as the one chosen by the investor.
5. The electricity price in year t (P_t^e) is assumed to depend both on income and demand in the current year and is subject to exogenous shocks, i.e.
$$P_t^e(Q_t, X_t) = Y_t^{-\varepsilon_i/\varepsilon_p} Q_t^{1/\varepsilon_p} X_t \tag{2}$$
where Y_t is the disposable income in year t and ε_i and ε_p denote the income and price elasticity, respectively. X_t is the exogenous shock, which is assumed to be an independent random variable with known distribution for each t.
6. As has been already explained in Section 2.1, wind when combined with pumped storage is able to affect the timing of supply and thus to benefit from the price fluctuations within a year. Thus the average price of electricity per kWh sold by a wind + hydro combination is higher than that of a standard wind. This is represented in the model by the price premium p, which denotes the price increment in percentage of the yearly electricity average price at the market.
7. The capital costs are annualized, representing a situation where the overnight construction costs are covered by a loan with the annualized capital costs being the yearly installments of such a loan. The operations and maintenance cost depend not only on the number of the power plants of the individual technologies, but also on the electricity supply in the given year, Therefore the yearly costs $c(n_t^w, n_t^h, q_t^w)$ of the investor are a function of n_t^w, n_t^h and q_t^w. The yearly income of the investor can be calculated as
$$\pi(n_t^w, n_t^h, q_t^w, X_t) = P_t^e(Q_t, X_t) q_t^w (n_t^w + (1+p) n_t^h) - c(n_t^h, n_t^w, q_t^w) \tag{3}$$

Table 1
Cost data.

		Yearly production	Ann. capital costs/plant	Variable costs (O&M + fuel + permit expenses)
Wind	Germany	25,916.9 GWh/a	275.9 Mio. €/a	24.90 €/a
	Norway	6120.5 GWh/a	535.8 Mio. NK/a	204.78 NK/a
Wind + hydro pump storage	Germany	25,916.9 GWh/a	543.1 Mio. €/a	32.08 €/a
	Norway	6120.5 GWh/a	1054 Mio. NK/a	263.78 NK/a

Source: calculated from [11] IEA, 2010.

Under these assumptions the investor's problem can be formulated as

$$\begin{aligned}
&\max_{u_t^c, u_t^w} \quad E\left[\sum_{t=0}^{T-1} \frac{1}{(1+r)^t} \pi(n_t^c, n_t^w, q_t^w, X_t)\right] \\
&n_{t+1}^w = n_t^w + u_t^w \qquad\qquad t = 0, \ldots, T-1 \\
&n_{t+1}^h = n_t^h + u_t^h \qquad\qquad t = 0, \ldots, T-1 \\
&n_0^w = 0 \\
&n_0^h = 0 \\
&n_t^w + n_t^h \leq n \qquad\qquad t = 0, \ldots, T-1 \\
&u_t^w + u_t^h \leq 1 \qquad\qquad t = 0, \ldots, T-1 \\
&u_t^w \in \{0, 1\} \qquad\qquad t = 0, \ldots, T-1 \\
&u_t^h \in \{0, 1\} \qquad\qquad t = 0, \ldots, T-1 \\
&q_t^w \quad - \quad \text{random variable with known distribution} \qquad t = 0, \ldots, T-1 \\
&X_t \quad - \quad \text{random variable with known distribution} \qquad t = 0, \ldots, T-1
\end{aligned} \tag{4}$$

where r is the subjective discount rate, n_t^w, n_t^h are the state variables, and u_t^w and u_t^h the control variables that are binary and represent the decision of the investor to invest in year t into a wind/wind + hydro power plant, respectively.

The resulting problem is a stochastic optimal control problem in discrete time with all the underlying variables being discrete in each time step. Thus it can be solved by recursive dynamic programming. The solution is then the optimal control in terms of feedback control telling the investor the optimal action for each time step and each possible state in that time.

To analyze the impact of the individual features of the model (impact of climate policy, wind load uncertainty), this output is further processed. In the results section, two indicators of the optimal control are reported: the mean amount of wind + hydro farms that are built within the planning period, and the value of the firm. The mean value of the firm is directly given by the value function in the first year that is derived by dynamic programming. For the average number of wind + hydro plants, Monte Carlo simulations are used. Future load and price shocks are simulated and for each simulation the feedback optimal control is used to extract the decision realized in that simulation. These decisions are then used for the calculation of the average investment into wind. In addition, these can be used to calculate the sum of the discounted profits over the planning period in each simulation, which gives us a distribution of the value of the firm as well.

For the application, the values of the individual parameters have to be estimated, the functional forms and the remaining data still have to be specified. This is explained in more detail in Section 2.3.

2.3. Data

In our paper the investment decisions of the producers are exemplarily surveyed in the countries Germany and Norway. The producers can choose between a farm of wind power plants and a farm of wind power plants in combination with a hydro pump storage plant. Both investment opportunities are adjusted so that the maximum output per year (at the respective average load) is the same. Furthermore, the ratio of the size of the wind farm, respectively, the combination of wind farm and hydro pump storage in Norway and Germany is equal to the ratio of the size of the two electricity markets (Q_0). Bueno and Carta [8] calculate the optimal size of the pump storage plant in relation to the wind farm and derive the ratio of 1:3. We use this ratio together with their estimate for the electricity loss caused by the pump process in the hydro pump storage plant of 0.1128 to calculate the setting of the combination. The cost estimates we use are taken from the 2010 IEA report [11] and summarized in Table 1. To derive the costs in € rather than US$, we used the exchange rate given in the IEA report [11] of 0.68 and the same measure (average exchange rate of 2008) for the translation of € into Norwegian Kroner at 8.22 (OECD [12]).

The load factor of the wind power plants is assumed to be normally distributed around a mean of 23% (according to [11]) with the standard deviation of 6% (as estimated for Europe in Atkinson et al. [13]).

There is a large amount of literature estimating the demand and its elasticity for electricity. Two often cited survey articles in this stream are Dahl [14] and Espey and Espey [15]. Together, they analyze some 84 articles with estimations of the elasticity for electricity. For modeling our price process, we rely on the basic model to keep the analysis transparent. The elasticities are thus estimated as follows:

$$\ln Q_t = \varepsilon_p \ln P_t^e + \varepsilon_i \ln Y_t + X_t \tag{5}$$

with x_t denoting the error term. The articles also calculate mean values of the estimates found in the analyzed articles for Eq. (6). The authors report an interval with the mean price elasticity of demand ε_p at −0.80 and the mean income elasticity ε_i at 0.93. Those using the form in (6) exactly estimate the price process used in our model described given by Eq. (2). For the stochastic shock (error term in (6)) we assume a normal distribution with mean 1 and standard deviation of 0.2 (which is approximately the size of the variance of the error term when estimating Eq. (6) with our underlying data).

We model the disposable income using a starting value Y_0 from 2009 and the average annual growth rate y of the last 20 years (1990–2009). As the firm has no investments at time $t = 0$, we take the actual total gross electricity generation of 2009 as the original supply in the market Q_0 and assume that, respectively, the big electricity producers of a country simultaneously take the same decisions. The data is obtained from Eurostat and the OECD and summarized in Table 2.

The considered planning period T is chosen as 30 years and following the standard assumptions in this stream of the literature, we assume a discount rate r of 0.05. Each firm is allowed to invest a maximum of four times.

Note from the data, that the difference between the "Germany case" and the "Norway case" lies in two characteristics: the size of the market and the electricity price process (and the underlying parameters).

Table 2
Price process data.

	Y_0	y	Q_0	N
Germany	2445.5 Bio. €	0.0288	577,380 GWh	4
Norway	2264.3 Bio. NK	0.0389	136,353 GWh	5

Source: EUROSTAT (2010), OECD (2010).

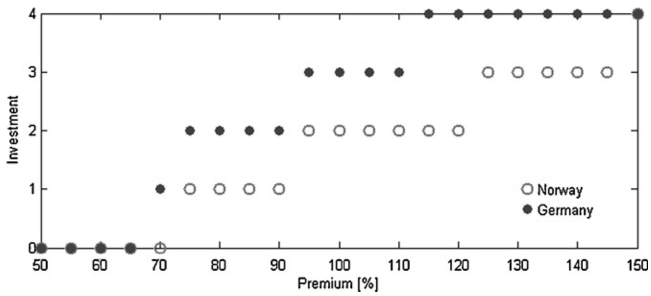

Fig. 2. Average investments into wind–hydro at the end of the planning period for different levels of price premia.

3. Model results and policy analysis

3.1. Price premium

An investment into the combination of a wind farm and a hydro pump storage plant conveys the following characteristics: (a) the (uncertain) output of the wind farm is the same as without the hydro pump storage, but (b) the producer now has the opportunity to save some output if the prices are low and sell the output plus the saved electricity if prices are high. Thus (c) on average the producer earns a higher price per unit of output, i.e. he receives a price premium for having the opportunity to postpone the selling of current production. This premium has to outweigh the (d) investment costs for the hydro plant, the variable (O&M) costs of running the hydro pump storage plant and the (small) loss of output through the storage process.

Fig. 2 shows the average number of investments into the combination at the end of the planning period for different levels of price premia. One can see that only with a price premium as high as 70% in Germany and 75% in Norway the combination gets relatively profitable and the producers invest into it at least once. To get the maximum average number of investments, a premium of at least 115% would be needed in Germany and 150% in Norway. Such high differences in the average price per output unit cannot be realistic. For example, Castronuovo and Lopez [16] calculate the optimal operation and size of a wind–hydro power plant combination. They find the yearly average per unit profits of the combination to be 20.12% higher than the per unit profits of an equally sized wind farm. Thus, we can conclude that today the investment into a combination of a wind farm and a hydro pump storage plant without public support is not profitable for an electricity producer compared to only investing into a wind farm.

Two factors we do not consider in our study are grids and economies of scale. One can think of the additional costs surrounding the transmission of the electricity from the wind farm to the pump storage plant and back into the system as an increase in the variable costs of each produced unit. These costs are higher the farther the wind farm is away from the pump storage plant or in the periods (high-peak vs. low-peak) during which the electricity is transported. Thus, a large fraction of the literature shows that the combination is most profitable on small islands and could even serve as base-load on larger islands (see, e.g. the literature review in Anagnostopoulos and Papantonis [6]). In our framework, taking into account the costs of grid adjustments would increase the threshold premium needed to make the combination relatively profitable. Economies of scale work in the other direction. So a bigger wind farm or, e.g. an already existing bigger hydro pumped storage plant can produce the electricity at lower per unit costs, which will result in a lower threshold premium.

3.2. Investment subsidy

Due to the positive externalities of the combination (see Section 1), it makes sense for a country to support the investment into these combinations. For example Norway supports the investment into the combination by paying a subsidy on the investment costs before the project starts. This subsidy would need to be high enough to make up for the difference in the premium needed (as seen in the chapter before) and a realistic premium.

Fig. 3 shows the average number of investments into the combination at the end of the planning period for different levels of capital cost subsidies. The different curves are shown for a variation of price premia between 0% and 100%. For realistic premia values (i.e. between 10% and 30%) the threshold subsidy to trigger at least one investment into the combination in Germany and Norway lies between 35% and 50%. To get the maximum average number of investments, a subsidy of up to 70% in Germany and 90% in Norway would be needed. In general, one can see that the investment activity of the producers is much more sensitive to an increase in the subsidy in Germany than in Norway. This can be explained by the relatively higher threshold level needed to trigger investments in the Norwegian market, i.e. prices start relatively lower in Norway due to the relatively higher already installed capacity in $t = 0$ in Norway. Afterwards the follow-up investments happen

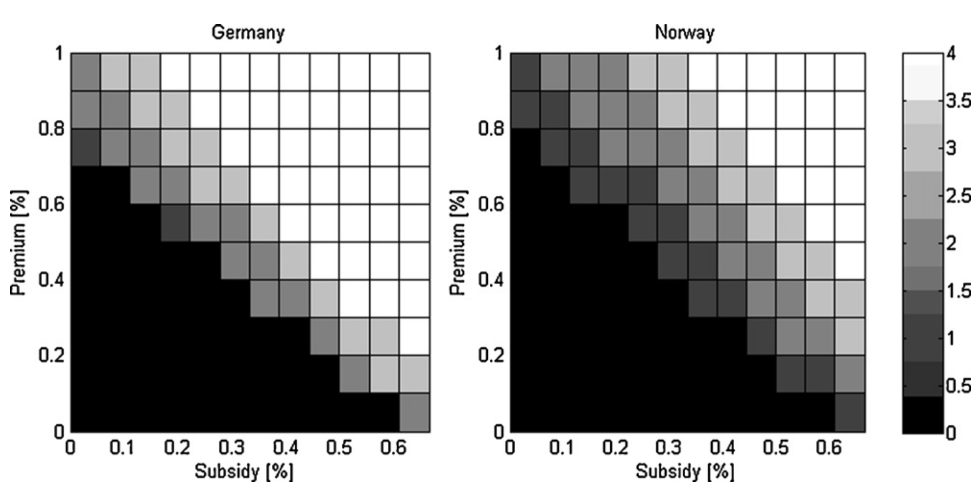

Fig. 3. Average investments into wind–hydro at the end of the planning period for different levels of capital cost subsidies.

later due to the higher number of big firms investing at the same time and the higher (in absolute terms) price level.

Since in our framework we compared the investments into wind farms and the investments in a combination of wind power with hydro pump storage plants, the introduction of a likely Swedish-Norwegian tradable green certificates system, which would affect both types of plants symmetrically, would in general not change our results. The results would only change if policy makers would allocate different amounts of certificates to units of electricity produced by wind or water plants and categorize the electricity produced by the hydro pump storage plant as electricity generated by water rather than by wind. In that case the result in our framework would be a decreased (if the allocation is in favor of water; increased otherwise) threshold premia. Producers will earn an uncertain but positive additional amount per unit produced.

4. Conclusion

This paper has presented a model for the economic evaluation of the adoption of a hybrid technology combing wind power and hydro pumped storage. We have chosen the market situation in Germany and Norway as case studies and explicitly accounted for uncertainty about the development of the electricity price and the market effects of new capacity additions, the intermittency of wind leading to a volatile load and the policy of an investment subsidy.

While the stabilization of profits and its raise by a premium from being able to sell at peak prices might appear attractive, our study shows that without substantial public support the technology is not profitable and will not be adopted for realistic premia. If grid stabilization, CO_2 mitigation and other objectives than profit-maximization enter the objective, there is thus a case of intervention to promote this type of technology.

Apart from the conventional policy measures ranging from feed-in tariffs to investment subsidies, another important dimension recommended to policy makers for consideration is the investment into R&D to decrease the costs and increase the efficiency of the technology in general. Rather than supporting investments today with relatively high costs compared to other green technologies, this can prove to lead to a faster diffusion of the technology at lower cost. Further research should also try and include factors that have not been considered explicitly in this analysis: grids, economies of scale and – in the case of Norway – the planned green certificate system.

Finally, two considerations to be explored in follow-up work on wind generation with storage are (a) the possibility to save on local storage using existing hydro dams as “batteries”, and (b) to analyze the Nordic market from a top-down view according to the same principle, where, e.g. Denmark feeds wind power into the grid, while Norway provides the base load from large-scale hydro.

Nomenclature

State variables

n_t^w number of wind farms that the investor has built prior to year t

n_t^h number of wind + hydro power plants that the investor has built prior to year t

Control variables

u_t^w number of wind farms the investor decides to build in year t

u_t^h number of wind + hydro power plants the investor decides to build in year t

Random variables

q_t^w yearly output [MWh] of one power plant in year t

X_t multiplier representing the electricity price shock in year t

Secondary variables

Q_t yearly aggregate electricity supply [MWh] in the market in year t

Y_t yearly income proxy [EUR]

$P_t^e(Q_t, X_t)$ average electricity price [EUR/MWh] in the market in year t

$c(n_t^w, n_t^h, q_t^w)$ yearly costs [EUR] of the investor as a function of the number of owned coal fired and wind power plants. Account for both the operational and maintenance costs and the annualized capital costs needed for construction

$\pi(n_t^c, n_t^w, q_t^w, X_t)$ yearly profits [EUR] of the investor as a function of the number of owned coal fired and wind power plants

Parameters

t time [years]

r Subjective discount rate

n upper constraint on the number of plants constructed by the investor in the planning period

p price premium of the wind + hydro technology

T planning period in years

Q^{fixed}, N parameters for the aggregation of supply. Fixed supply in each year (MWh) and the multiplier of new investment, respectively

Y_0, y income parameters. Starting value [EUR] and growth rate, respectively

ε_i, ε_p income and electricity price elasticity, respectively

μ_w, σ_w^2 mean and variance of the yearly output of one wind farm

μ_x, σ_x^2 mean and variance of the shock process

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